ERDC/CERL TR-00-25

Construction Engineering Research Laboratory

US Army Corps of Engineers®
Engineer Research and Development Center

Electrical and Natural Gas Rates for Cooling in Major Army Installations

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August 2000

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Foreword

This study was conducted for the Directorate of Military Programs, Headquarters, U.S. Army Corps of Engineers (HQUSACE), under Project 4A262784AT45, "Energy and Energy Conservation"; Task CF; Work Unit X60 "Hybrid Cooling Technologies." The technical monitor was John Lanzarone, CEMP-ET.

The work was performed by the Energy Branch (CF-E) of the Facilities Division (CF), Construction Engineering Research Laboratory (CERL). The CERL Principal Investigators were Dr. Carl Feickert and Dr. Chang W. Sohn. Larry Windingland is Chief, CEERD-CF-E; and L. Michael Golish is Chief, CEERD-CF. The CERL technical editor was William J. Wolfe, Information Technology Laboratory. The associated Technical Director was Gary W. Schanche, CEERD-CV-T. The Acting Director of CERL is Dr. Alan W. Moore.

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1 Introduction

1.1 Background

The U.S. armed services and related supporting structures buy a significant amount of electrical power from the private sector during any given month. In an era of deregulation, environmental awareness, and dwindling reserves of fossil fuels, it has become imperative that the U.S. government have access to the most cost effective mechanisms to minimize overall energy consumption.

FY97 data show that the total cooling capacity of air-conditioning equipment in the Army is 932,709 tons of cooling. The majority of the air-conditioning equipment in the Army is electrically powered. The Army's electrical bill in FY97 was over $569M, and even under the downsizing trend of Army facilities, the electrical bill increased from $555M in FY95 to $569M in FY97 (Department of the Army 1998). Typically, more than a third of the total electrical utility cost is incurred by operation of air-conditioning and refrigeration equipment. According to a detailed end-use study of electrical energy at Fort Hood, TX, 54 percent of the peak power demand is for cooling, and 33 percent of the total electricity consumed was for cooling applications (Akbari and Konopacki 1995). The annual electrical utility cost for providing air-conditioning for the Army, is therefore estimated at over $200M.

Of approximately 5,000 large water-cooled chillers sold in the United States in 1998, roughly 93 percent are reported to be electrically driven (Nowakowski and Gramlich 1999). Large scale natural gas-fueled cooling systems have been demonstrated at a number of DOD facilities as an alternative to the electrically-driven cooling systems that are predominant in the DOD facilities (Sohn et al. 1997). Natural gas cooling systems offer savings in cooling cost by reducing on-peak electrical demand and, at certain sites, by reducing the cost of energy by using natural gas instead of electricity. The natural gas cooling systems (described fully in the *Natural Gas Cooling Equipment Guide* 1995) and natural gas/electric hybrid cooling systems (discussed in detail in Nowakowski and Gramlich 1999) have gradually become accepted by the industry as an alternate to the electrical cooling systems. The economical feasibility of these gas or hybrid cooling systems depends on the cost differential between the electricity and the natural gas at a given Army installation.

Natural gas-powered cooling systems have been introduced into the market during the last decade as an alternative to the electrically driven cooling systems. According to a Renewables and Energy Efficiency Planning (REEP) study (Nemeth et al. 1995), the annual savings potential of natural gas cooling systems for DOD facilities is estimated to be $70M. To accelerate introduction of natural gas cooling technologies to DOD facilities, Congress provided $25M for the period of FY93-95 for procurement of gas cooling systems for DOD installations (Sohn et al. 1997). Further, the Strategic Environmental Research and Development Program (SERDP) contributed toward implementing gas cooling technologies in DOD installations. A number of gas cooling systems were also installed with support from the Federal Energy Management Program (FEMP). This study was undertaken to support these efforts by gathering the field information needed to create realistic cost models to evaluate electric-natural gas hybrid cooling systems.

1.2 Objectives

The objectives of this study were: (1) to compile current electrical and natural gas rate schedules at the major Army installations, and (2) to develop installation-specific fuel cost models based on the unit energy and the unit energy demand, for application of electric-natural gas hybrid cooling systems in Army installations.

1.3 Approach

Major Army installations were selected from the U.S. Army Forces Command (FORSCOM) and the Training and Doctrine Command (TRADOC) Internet home pages. Current electric and natural gas rates were collected through direct contact with each installation, or from servicing vendors listed in the installations' World Wide Web (WWW) home pages. The installation-specific cost equation was developed in terms of unit energy in kWh and Therms (thm), and unit energy demand in kW and thm/day.

1.4 Scope

Models were developed for this study using routine life cycle cost calculations. Specific projects related to individual installations should supplement this information with up-to-date prevailing rate schedules from the installations under study.

1.5 Mode of Technology Transfer

The installation-specific cost model in this report can be used by project planning at the installations under study, or by their serving Corps districts. It is anticipated that the information derived from this study will be used to update the cost basis in the REEP program. The information in this report will also be presented as a technical paper to the USACE Electrical and Mechanical Training Conference.

1.6 Units of Weight and Measure

U.S. standard units of measure are used throughout this report. A table of conversion factors for Standard International (SI) and common marketing units (for natural gas) is provided below.

SI conversion factors		
1 in.	=	2.54 cm
1 ft	=	0.305 m
1 yd	=	0.9144 m
1 sq in.	=	6.452 cm^2
1 sq ft	=	0.093 m^2
1 sq yd	=	0.836 m^2
1 cu in.	=	16.39 cm^3
1 cu ft	=	0.028 m^3
1 cu yd	=	0.764 m^3
1 gal	=	3.78 L
1 lb	=	0.453 kg
1 kip	=	453 kg
1 psi	=	6.89 kPa
°F	=	(°C x 1.8) + 32
Common marketing units for natural gas		
1 thm	=	10^5 BTU
1 Dthm	=	10^6 BTU
1 thm	=	(100/1.025) CF
1 CCF	=	100 CF
1 CF	=	1.025 x 10^3 BTU
1 MCF	=	1000 CF

2 Description of Rate Structures at Major Army Installations

2.1 Selection of Army Installations

The FORSCOM and TRADOC installations listed in their Internet home pages were contacted for data on the electricity and natural gas rates. Data for this report was collected in a traditional investigative manner. Data were compiled primarily through one-to-one verbal interaction between interviewer and resource person at an installation, utility, or government data collection center such as the Defense Energy Support Center (DESC). Table 1 lists (alphabetically) the surveyed installations.

This chapter outlines several different pricing structures available to Army installations for gas and electricity, to provide installations with the information to determine the most cost effective option for cooling their facilities. Tables 2 and 3 summarize the raw data collected from each installation. Chapter 3 elaborates on this data and gives explanatory comments for the entries found

Table 1. Surveyed FORSCOM and TRADOC installations.

FORSCOM	TRADOC
Fort Bragg, NC	Fort Benning, GA
Fort Buchanan, PR	Fort Bliss, TX
Fort Campbell, KY	Fort Carlisle, PA
Fort Carson, CO	Fort Chaffee, AR
Fort Drum, NY	Fort Eustis, VA
Fort Hood, TX	Fort Gordon, GA
Fort Irwin, CA	Fort Huachuca, AZ
Fort Lewis, WA	Fort Jackson, SC
Fort McPherson, GA	Fort Knox, KY
Fort Polk, LA	Fort Leavenworth, KS
Fort Riley, KS	Fort Lee, VA
Fort Stewart, GA	Fort Leonard Wood, MO
	Fort McClellan, AL
	Fort Monroe, VA
	Fort Rucker, AL
	Fort Still, OK

2.2 Electric Rate Structure

Several typical distinct pricing structures apply to large consumers of electrical power in the continental United States (CONUS). The pricing is typically driven by two primary factors: the total energy (kWh) consumed, and the "demand" (in kW). However, certain ancillary parameters may modify the total functionality, such as ratchets, fuel cost, co-generation, etc. Most electric rate structures can be categorized as one of the following three types: (1) energy plus straight demand, (2) energy plus multi-tiered demand, and (3) real time pricing (RTP).

2.2.1 Energy Plus Straight Demand

The "energy plus straight demand" is the most traditional electrical rate structure. In this structure, the electrical bill consists of two parts—one for the energy charge based on the total kWh consumption during the billing period, and the other for the demand charge based on the billing demand in kW during the same billing period.

The energy charge is typically calculated by the multiplication of total kWh consumed during the billing period, times the predetermined cost of each kWh of energy. Frequently, the kWh rate can be different for any kWh consumed during on- or off-peak periods. The demand charge is calculated by multiplying the billing demand in kW times the predetermined cost of each kW.

The billing demand is typically determined by one of the following: the actual highest on-peak demand for the billing period, a certain predetermined percentage (called the ratchet percentage) of the highest on-peak demand during the preceding 11 months, or the contract demand during the billing period. For some installations, the billing demand for the winter months is defined by the ratchet percentage times the highest on-peak demand of the last summer months. In this rate structure, a reduction in the highest on-peak demand during the summer months will reduce the demand charges throughout the year, including the winter months.

2.2.2 Energy Plus Multi-Tiered Demand

The "energy plus multi-tiered demand" structure is similar to the "energy plus straight demand" structure described above. The major difference between the two structures is the way the demand charge is calculated. The simplest of these structures will partition the demand into several predetermined demand bins, each at a fixed cost. The total energy may also be similarly partitioned, with the total number of bins ranging typically between one to four for either or both

variables. A fixed rate for total energy and demand would be a special case in this category. The sum of each type of bin equals the total billing demand and consumed energy respectively.

A more complex form of the energy plus multi-tiered demand structure derives from an incremental decomposition of the total energy in terms of the billing demand. Demand charges are as before, but now the total energy used is partitioned into several predetermined rate bins, each of which is some multiple of the billing demand, and is priced accordingly. The sum of these rate bins (units of kWh) equals the total energy consumed.

2.2.3 Real Time Pricing (RTP)

In the real time pricing (RTP) schedule, the customer is charged by what the market can sustain. The customer is notified as to the hourly rates for each kWh, normally 24 hours in advance. Most RTP schedules have very low electricity cost during off-peak hours or when demand is low. During on-peak hours or when demand is high, however, the kWh cost becomes extremely high. Under this schedule, costs may vary from $0.02-0.03/kWh during off-peak hours, to $0.10-1.0+/kWh during on-peak periods. When the overall demand is high, it is not unusual for the cost of electricity to be posted higher than a dollar per kWh. With a RTP schedule, an exact a priori calculation of electrical cost is not possible.

2.2.4 Marginal Cost of Electricity at Each Installation

When new electrical cooling equipment is installed, the most important electrical cost information is the marginal rate. The marginal energy cost is defined as the cost of electricity for each additional kWh consumed above the current level. The marginal demand cost is defined (in particular, for the summer months) as the incremental demand cost for each kW added onto the annual peak demand. Almost invariably, this occurs during summer afternoons where electrical cooling equipment contributes to increments of the on-peak demand and consumption (in, kWh) at premium energy cost.

For example, suppose a particular installation had a straight energy cost of $0.075/kWH, and an uncomplicated demand charge of $8.00/kW. If three security lights, each 100W, are run (during the evening) for 10 hours, then 3kWH of energy are consumed at a cost of $0.225. Note that the additional (demand) power of 3kW during the night does not contribute to an increase in the peak demand. By comparison, a 3kW window air conditioner that is run for 1 hour during a heat wave will also consume 3kWH of energy. Note however that the additional 3kW (de-

mand) for the air conditioner will increase the peak demand by 3kW for a particular billing period. The air conditioner's demand cost during this hour of premium use will be $24.00, and will require an additional $0.225 for the 3kWH of electrical energy. Such scenarios, make a compelling argument for peak shifting and power conservation programs. Table 2 shows that incremental energy cost for each kWh electricity and incremental cost for each kW of on-peak demand at each installation, based on the raw data collected for this study.

Table 2. Marginal electrical cost at Major Army installations.

Installation	Energy cost ($/kWh)	Demand charge ($/kW)	Electric Utility
Fort Benning, GA	0.10355	14.15	Georgia Power Co.
Fort Bliss, TX	0.01906	1.52	El Paso Electric Co.
Fort Bragg, NC	0.03261	7.55	CP&L
Fort Buchanan, PR	0.059	7.70	Puerto Rico Electric Power Authority
Fort Campbell, KY	0.02265	12.60	TVA
Fort Carlisle, PA	0.0481	2.89	PP&L (two rate structures)
Fort Carson, CO	0.04718	0.1941 x kW/day	Colorado Springs Utilities
Fort Chaffee, AR	0.0257	5.13	OG&E Electric Service
Fort Drum, NY	0.09+/-.03	6.19	Niagara Mohawk Power Corp
Fort Eustis, VA	0.03519	5.2	Virginia Power
Fort Gordon, GA	0.1035	14.15	Georgia Power
Fort Hood, TX	0.0243	8.63	Texas Utilities Elec. Co.
Fort Huachuca, AZ	0.04647	10.07	Tucson Electric Power
Fort Irwin, CA	0.067	6.60	Southern California Edison Co.
Fort Jackson, SC	0.0384	13.72	South Carolina Electric and Gas
Fort Knox, KY	0.0244	8.54	Louisville Gas and Electric Co.;
Fort Leavenworth, KS	0.0287	3.75	KPL
Fort Lee, VA	0.03519	5.2	Virginia Power (proprietary)
Fort Leonardwood, MO	0.025	6.185	SHO-ME Power
Fort Lewis, WA	0.0214	4.43	Tacoma Public Utilities
Fort McClellan, AL	0.0741	0.76	Alabama Power
Fort McPherson, GA	0.025222	—	Georgia Power Co.
Fort Monroe, VA	0.0167	10.52	Virginia Power
Fort Polk, LA	0.02905	2.87	Louisiana Power and Light Co.
Fort Riley, KS	0.02787	3.75	KPL
Fort Rucker, AL	0.0921	—	Alabama Power
Fort Sill, OK	0.034	—	PSO + Cogeneration capability
Fort Stewart, GA	0.10355	14.15	Georgia Power Co.

Note: If not specified otherwise in text, the rate data were current during the data collection period of February to December 1999.

2.3 Natural Gas Rate Structure

Gas has many of the same pricing parameters that characterize the electrical industry. However, because it has been deregulated for a longer period of time, some of the volatility that characterizes the present electrical industry is no longer a market factor. There are differences such as transportation, pumping and storage costs, and BTU content per unit volume. Furthermore, when compared to electricity, the ability to store natural gas for use during periods of high demand is a significant attribute.

Throughout the United States, gas and liquid petroleum products are marketed and sold in units of Cubic Feet (CF), Therms (thm) and British Thermal Units (BTUs). The BTU is the translatable unit of energy in the English system of measures, such that 1 BTU/sec = 1055.1 Watts in the MKS system. The conversion table on p 9 provides the conversion relationships between these common commercial units. The factor, 1.025 $\pm$ 3%, represents the nominal energy content factor for natural gas measured at standard temperature and pressure (STP), and is often referred to as the "BTU factor."

2.4 Marginal Cost of Natural Gas

When natural gas cooling equipment is installed, the most important natural gas cost information is the marginal rate. Typically, the cooling operation runs during the summer when the gas cost is lowest. This is the most important advantage of natural gas cooling over electrical cooling, as shown by the raw installation data of this report. Table 3 lists the incremental cost for each therm of summer rate at each surveyed installation.

Table 3. Marginal natural gas cost at Major Army installations.

Installation	Energy Cost ($/thm)	Demand Charge ($/thm)	Comment
Fort Benning, GA	0.396	0.445	
Fort Bliss, TX	0.331	—	Gas and transportation
Fort Bragg, NC	0.30315	0.85	
Fort Buchanan, PR	—	—	OCONUS, no NG available
Fort Campbell, KY	0.335	0.0035	
Fort Carlisle, PA	0.7326	—	Gas and transportation
Fort Carson, CO	0.382	—	Does not include transportation data.
Fort Chaffee, AR	0.4538	—	
Fort Drum, NY	0.343	1.15838	SC-8 Transportation can add 3% more
Fort Eustis, VA	0.330	1.018	For > than contracted
Fort Gordon, GA	0.521	—	
Fort Hood, TX	0.396	—	DPW Data (March to September 1999)
Fort Huachuca, AZ	0.320	—	Gas and transportation
Fort Irwin, CA	0.493	—	No NG, transported propane gas
Fort Jackson, SC	0.345	—	Propane (no gas), $ fluctuate +/- 10%
Fort Knox, KY	0.405	—	
Fort Leavenworth, KS	0.1976	—	Fuel and transportation
Fort Lee, VA	—		Proprietary, but similar to those of Fort Eustis
Fort Leonardwood, MO	0.3316	—	Omega Pipeline Company (May, 2000 data)
Fort Lewis, WA	0.3455	1.99	Puget Sound Energy (effective : 4-2000)
Fort McClellan, AL	0.6533	—	Gas and transportation
Fort McPherson, GA	0.361	—	Gas and transportation
Fort Monroe, VA	0.5889	—	
Fort Polk, LA	0.495	—	Gas and transportation, contract by DESC
Fort Riley, KS	0.2935	—	Gas and transportation, contract by DESC
Fort Rucker, AL	0.2412	1.098	Reliable data from DPW
Fort Sill, OK	0.338		Transportation plus commodity
Fort Stewart, GA	0.34	—	Gas and transportation.
Note: If not specified otherwise in text, the rate data were current during the data collection period of February to December 1999.			

3 Installation-Specific Rate Structures

The following sections describe the installations listed in Table 1 (in alphabetical order) and give a most complete summary of electrical and gas data for each location. The data is generally unique to each installation, and was obtained or deduced from various primary sources. Comments following each utility summary provide condensed explanations of how the typical entries listed in Tables 2 and 3 were obtained using the assumption of premium (summer) rates at their most expensive level.

3.1 Fort Benning, GA

3.1.1 Electrical

Electricity

- *Cost*: (2.5 $\pm$ 0.2)¢/kWh for Energy $\leq$ 20 GWH/Mn*
- *Cost*: [0.445 X (Energy/GWH) - 6.6]¢/kWh for Energy $\geq$ 20.5 GWH/Mn
- *Schedule*: MLM-1
- *Energy Charges*: (June through September):
  - ON-Peak = 9.0¢/KWH (1400 – 1900 hours, M-F, except holidays)
  - SHOULDER = 4.0¢/KWH (1200 – 1400 hours, M-F)
  - OFF-Peak = 1.4¢/KWH (all hours not included above)
- *Customer Baseline Load*: 1.3548¢/KWH (yearly average, for all types of above power)
- *Incremental Energy*: 3.4¢/KWH (spot market).
- *Demand Charges*: Transmission Service (June through September)
  - ON Peak kW = $14.15/kW
  - Economy kW = $4.15/kW.

Excess Reactive Demand shall be the kVAR which is in excess of one-third of the measured actual KW in the current month for each metered service point. Each

* GWH/Mn = gigaWatt hours per month, where 1 gigaWatt = 1 billion (10^9) Watts.

month excess kVAR will be billed at 27¢/ excess kVAR. There are additional fuel recovery costs, adjustments, and riders.

Comments: Choosing "ON Peak kW" for Demand, and including Customer Baseline Load with "ON Peak" energy gives the values for Table 2.

3.1.2 Gas

- *Demand Charge*: $0.456 / CCF
- *Rate Charges*:
  - First 20,000 CCF = $0.0788 / CCF
  - Next 80,000 CCF = $0.0872 / CCF
  - 100,000 CCF or more = $0.0576 / CCF
  - Firm Purchase Gas Adjustment (PGA), for all CCF = $0.3484 / CCF
- *BTU Factor*: unknown (and assumed to be 1.025).

Comments: Choosing Demand Charge, and including PGA for Rate Charges gives the values for Table 3.

3.2 Fort Bliss, TX

3.2.1 Electrical

- *Demand Costs*:
  - Firm Demand = 16,000 KW X $23.25/KW = $372,000
  - Interruptible Demand = [Total Demand - Firm Demand] X $1.52/KW
- *Tiered Energy Costs:*
  - Firm Energy = The fractional part of [Firm Demand to Total Demand] X Total Consumed Energy, in KWH X 0.853¢/KWH
  - Interruptible Energy: The fractional part of [Interruptible Demand to Total Demand] X Total Consumed Energy, in KWH X 0.545¢/KWH
- *Fuel Adjustment Costs*: Total Consumed Energy (in KWH) times $0.01361/KWH for all Total Consumed Power.

Comment: Choosing Interruptible Demand and Energy, plus Fuel Adjustments gives the values listed in Table 2.

3.2.2 Gas

Gas is provided by Southern Union Gas Co., under rate schedule E5.

Transportation Charge (@ 14.9 psi) $0.0315 / CCF

Price for actual gas fluctuates and for the months of April to October of 1999, has trended upward from $2.1 to $3.2 / MCF; the 5-year average is of the order of ($2.25± 10%) / MCF.

BTU Factor: unknown (and assumed to be 1.025).

Comment: Adding transportation to $3.0/Dthm gas gives the value listed in Table 3.

3.3 Fort Bragg, NC

3.3.1 Electrical

- *Energy Charges*: All energy billed at $0.03261/KWH
- *Billing Demand Charges*:
  - First 5000 KW billed at $11.25/KW
  - Next 5000 KW billed at $10.25/KW
  - Remaining KW of billing demand billed at $9.25/KW
- *Present Billing Demand*: Set at 80 percent of 96,222 KW, which was set during August 1998.

3.3.1.1 Interim RTP Billing Adjustment (LGS Accounts)

There exists a demand driven billing adjustment, that results in a net reduction of total electrical costs to Fort Bragg. This is computed as: (Billing Demand, in KW) X [1.0 - 0.76] X $9.25/KW, which is subtracted from the total billing costs.

3.3.1.2 Facilities Demand Charge Adjustment (LGS Accounts)

There exists a Transmission / Transformation charge based on the above billing adjustment, in units of KW, and charged at: $2.17/KW.

Comment: Collecting Total Demand components and energy gives the entries for Table 2.

3.3.2 Gas

- *Gas Price*: $0.30315 / thm
- *Demand Charge*: $0.85 / thm (0-70,000 thm)
- *Demand Charge*: $1.125 / thm (> 70,000 thm)
- *Average BTU Factor*: 1.043.

3.4 Fort Buchanan, PR

3.4.1 Electrical

- *Demand Costs*: Total Demand (in KVA) X $7.70/KW.
- Tiered Energy Costs:
  - First Tier = 300 X [Total Demand, in KVA] X a fixed percentage of the total demand, currently set at 93.9944 percent. The resulting Tier-1 costs is this number, in units of KWH, times $0.032/KWH.
  - Second Tier = Total Consumed Energy (in KWH) - the previously computed Tier-1 Energy (in KWH). The resulting Tier-2 cost is this number, in units of KWH, times $0.028/KWH.
- *Fuel Adjustment Costs*: Total Consumed Energy (in KWH) times an adjustable fuel factor, typically of the order: ($0.01850 to $0.0310)/KWH for all Total Consumed Power.

Comment: Adding Fuel Adjustment and Second Tier rates gives energy values listed in Table 2.

3.4.2 Gas

Fort Buchanan apparently does not use any fossil fuels on base, save for a small amount of propane for cooking, as per conversations with Ms. Gillette (accounting) and Mr. Avlio Colon of DPW.

3.5 Fort Carlisle, PA

3.5.1 Electrical

Fort Carlisle purchases energy through a two tariff structure with PP&L. The tariffs change yearly and are available, under separate cover for the next 5 years. Approximately 63 percent of the total (monthly) energy is purchased through a DESC contract with PP&L's ENERGYPLUS CO, and the remaining 37 percent is purchased through PP&L's Regulated Rate LP-5. The precise percentage is defined to be close to 37.116 percent and constrains each tariff's monthly demand, as follows:

0.37116 = [Demand @ Reg. Rate LP-5]/[Demand @ ENERGYPLUS]

The energy allocated to each tariff is partitioned in the same ratio. In practice, this roughly divides the total monthly cost into equal amounts. The following rates are in affect for the year 2000.

3.5.1.1 PP&L's ENERGYPLUS Co

- *Energy Charges*: 3.73¢/KWH
- *Transmission Charges*: 0.340¢/KWH.

Note that there is a demand assessment at this rate, but there is no demand cost for the ENERGYPLUS tariff.

PP&L's Regulated Rate LP-5

- *Transmission Charges*: 0.304¢/KWH (of LP-5)
- *Distribution Charges*: 28.9¢ / Total Billing KW
- *Transition Charges*:
  - Total Billing Demand (ENERGYPLUS + LP-5) = $1.450/KW
  - First 200 X (Total Billing Demand) KWH at: 1.392¢/KWH
  - Next 200 X (Total Billing Demand) KWH at: 1.187¢/KWH
  - Remaining KWH of Total Energy usage billed at: 1.033¢/KWH.
- *Generation Charges*:
  - Billing Demand Rate, of LP-5, at: $4.251/KW
  - First 200 X (LP-5 Billing Demand) KWH at: 3.726¢/KWH.
  - Next 200 X (LP-5 Billing Demand) KWH at: 3.132¢/KWH.
  - Remaining KWH of LP-5 Energy usage billed at: 2.687¢/KWH.

Comment: PP&L supplies **both** the LP-5 and ENERGYPLUS service. Demand and energy are partitioned as above between the two rate structures, but otherwise co-mingled without regards to total amounts. Computing proper averages, using the above rates, ratios and assuming premium power, yields the values listed in Table 2.

3.5.2 Gas

Natural gas is purchased through DESC, with the price negotiated on a monthly basis. For the period of July 1998 to June 1999 the averaged Total Unit Cost = $6.414 (+$1.17, -$0.63) / MCF for gas purchased.

During this same period, the actual averaged Gas Cost = $2.272 (+$0.47, -$0.43) / MCF. The difference between gas and total costs is made up by the aggregate transportation and delivery costs. BTU factor = 1.037

3.6 Fort Campbell, KY

3.6.1 Electrical

- *Demand Costs*: (Total Demand (in KW)) X $12.60/KW

- *Energy Costs*: All energy, in KWH, X $0.02265/KWH
- *Facilities Rental Costs*: Contracted Demand (i.e., 52,000 KW) times $0.036/KWH.

Comment: Individual monthly "Billing Demand," is determined by greatest one hour consumption (of KW) for any particular month.

3.6.2 Gas

Gas is purchased through a cooperative agreement between Clarksville, TN and Fort Campbell. The rates are negotiated on a yearly basis, and DESC considers the rates to be quite favorable to Fort Campbell. Presently, the Demand rate is fixed at $0.03625 / MCF. The commodity rate is composed of a variable BTU factor times the following: transportation, Gas rate, BTU adjustments, and a Gross Margin mark-up. Only the Gross Margin is fixed by the annual agreement at $0.29360 / MCF; all of the other factors are variable. Over the past 8 months, the total actual Commodity Rate = $3.16 ± 0.3 / MCF, and BTU factor = 1.03.

3.7 Fort Carson, CO

3.7.1 Electrical

- *Determination of Demand*:
  - Maximum demand is the greatest 15-minute load during any time in the billing period adjusted upward by 1 percent for each 1 percent that the power factor of customer is below 95 percent lagging.
- *Billing Demand*:
  - *ON Peak*: the greatest 15 minute load during On-Peak hours in the billing period adjusted upward by 1 percent for each 1 percent that the power factor of customer is below 95 percent lagging.
  - *OFF Peak*: the greater of either (a) or (b), but not less than zero:

    (a) The greatest 15 minute load during Off-Peak hours in the billing period adjusted upward by 1 percent for each 1 percent that the power factor of customer is below 95 percent lagging, minus the On-Peak Billing Demand.

    (b) 75 percent of the Maximum Demand during the last 12 billing periods, minus the On-Peak Billing Demand.
- *Demand Charges*:
  - ON Peak billing demand = 19.41¢/kW/Day.
  - OFF Peak billing demand = 15.22¢/kW/Day.
  - The factor "1/Day" implies that the total (ON/OFF) Demand charges are computed as: Demand KW's X (ON/OFF) Demand Rate X Number of days per billing period.

- *Energy Supply Charges*:
  ON Peak = 4.68¢/kWh.
  OFF Peak = 1.99¢/kWh.
- *Electric Cost Adjustments*: Total ON-peak, plus total OFF-peak consumed power @ 0.03760¢/kWh.

Comment: Choosing ON Peak values for Demand and Energy with the inclusion of adjustments gives the entries listed in Table 2.

3.7.2 Gas

Gas is provided to Fort Carson by Colorado Springs Utilities, both commodity and transportation. At present, the actual detailed billing statements are confidential and are not available. The billing structure is some unknown admixture of the following tariffs.

- *Natural Gas, Special Contract Service-GCS.* As of 20 December 1999, this GCS-rate is thought to be only the "backup" tariff. The actual commodity is proprietary and is not available.
- *Firm Service*:
  - Demand Charge of Daily Contract Demand: $0.2407/MCF/Day.
  - Commodity Charge: $2.2077/MCF.
  - Unauthorized Overrun Charge: $40.0/MCF
  - Interruptible Service:
    Commodity Charge = $2.6438/MCF.
    Unauthorized Overrun Charge = $40.0/MCF
    Gas Cost adjustments apply in each case, and when applicable, are: $0.1450/MCF, (from billing records of May 1999). The factor "1/Day" implies that the total Demand charges are computed as: Demand MCFs X Demand Rate X Number of days per billing period.
- *Natural Gas, Firm Transportation Service-G6T*:
  - Firm Transportation Service:
    Transportation Demand Charge of Daily Demand:
    $0.0495/MCF/Day.
    Transportation Commodity Charge: $0.4266/MCF.
    Interruptible Backup Sales Service:
    Interruptible Backup Commodity Charge: $2.6438/MCF.
  - Daily Balancing Charge:
    Under/Over deliveries: $0.1791/MCF.
  - Monthly Balancing Charge: (Under/Over) deliveries (110 percent Charge / 90 percent Credit) of index.

  - Unauthorized Overrun Charges: $40.0/MCF.
- Natural Gas, Interruptible Transportation Service-G7T:
  - Interruptible Transportation Service:
    Transportation Commodity Charge: $0.4929/MCF.
  - Interruptible Backup Sales Service:
  - Interruptible Backup Commodity Charge: $2.6438/MCF.
  - Daily Balancing Charge:
    Under/Over deliveries: $0.1791/MCF.
  - Monthly Balancing Charge:
  - (Under/Over) deliveries (110 percent Charge / 90 percent Credit) of index.
    Unauthorized Overrun Charges: $40.0/MCF.

The DPW at Fort Carson provided the averaged Interruptible and Firm data (Table 4). Transportation is not thought to be included for the Firm data, and is unknown for the interruptible data. The BTU factor = 0.980, as per Office of the DPW.

Table 4. Averaged interruptible and firm data at Fort Carson, CO.

Firm Gas $/MCF	Interruptible Gas $/MCF	Month of Usage
$2.53	$1.91	April 1999
$3.45	$2.30	May 1999
$4.69	$2.36	June 1999
$5.70	$2.39	July 1999
$5.62	$2.55	August 1999
$4.44	$2.87	September 1999

Combined averaged Gas rates for Firm and Interruptible, for the above months, varies from $0.229/thm to $0.382/thm.

3.8 Fort Chaffee, AR

3.8.1 Electrical (Summer Rates)

- *Demand Costs*: Total Demand, in KW X $5.13/KW
- *Energy Costs*: All energy, in KWH, X $0.02361/KWH
- *Fuel Adjustment Credit*: = Total energy X 0.1037¢/KWH.

3.8.2 Gas

- *Distribution Charge*: $1.5183 / MCF
- *Cost of Gas*: $0.64072 / MCF

- *Commodity Charge*: \$2.4924 / MCF
- *BTU factor*: unknown (and assumed to be 1.025). Combining the above rates gives the entry in Table 3.

3.9 Fort Drum, NY

3.9.1 Electrical

Fort Drum's electricity is supplied through Niagara Mohawk Power Corporation under a Service Classification # 3A, and has similar constraints to those of natural gas (see below). Most of its electricity is Fixed Price "Option 2," with the election of Variable Electricity Supply Service "Option 1." The pricing structure for Option 2 electricity changes on a annual basis starting with September of 1998. This contract is in effect for a 5-year period, and the forecasted pricing structure is presently available under separate cover. The pricing structure of Option 1 electricity is determined on the open market, as it is consumed in real time.

- *Delivery Charges*:
  - Customer Charge = \$3,172.00
  - Distribution and Competitive Transition Charges (CTC) that are demand driven: (\$2.08+\$4.11) = \$6.19/kW
  - Reactive Demand Charges: \$1.02/kVA.

3.9.1.1 Option 2

- *Competitive Transition Charge (Energy)*:
  - ON Peak = 3.149¢/kWh for first 250 X [Billing Demand] KWH of total: (ON + OFF) KWH used
  - OFF Peak = 2.58¢/kWh for first 250 X [Billing Demand] KWH of total: (ON + OFF) KWH used
  - ON Peak = 2.217¢/kWh for remaining total: (ON + OFF) KWH
  - OFF Peak = 1.80¢/kWh for remaining total: (ON + OFF) KWH, not to exceed the individual limits of (ON/OFF) contracted load per month
- *Electricity Supply Charges (Summer Months)*:
  - Total ON Peak = 2.529¢/kWh
  - Total OFF Peak = 2.099¢/kWh
  - System Benefits Charge = Total contracted ON-peak, plus total OFF-peak loads @ 0.0620¢/kWh.

3.9.1.2 Option 1

- *Competitive Transition Charge (Energy)*:
  - ON Peak = 2.0820¢/kWh for > 400 hr use
  - OFF Peak = 1.689¢/kWh for > 400 hr use.

Electricity Supply Charges are determined in real time as consumed. During the 1999 summer Months, these charges ranged as follows: (ON/OFF) peak = (3.35 to 9.24)¢/kWh / (3.31 to 4.33)¢/kWh.

Comment: Assuming premium power, Option 1 electricity will be used during the ON Peak mode, at a rate of about 6 (+/-3)¢/kWh. Including transition charges and the above demand value, yields the entries listed in Table 2.

3.9.2 Gas

Fort Drum's deregulated gas pricing structure is composed of a transportation and a commodity cost. The transportation is provided by Niagara Mohawk Power Corporation, considered the "supplier of last resort" under a Service Class 8-Stand Alone tariff. The actual gas commodity is provided to Fort Drum through a DESC broker for the Northeast region, and billed to Fort Drum on a monthly basis through a separate billing statement. During the warm summer months of 1999, no gas was purchased through the vendor as a more competitive price was available through Niagara Mohawk's SC-8 standby sales, to follow.

General Transportation under SC-8

The cost associated with transportation is composed of three separate components: Transportation, Standby Sales Service, and Cashout, each with its own pricing structure.

Pricing for Transportation is the sum of the following:

- First 100 thm = $700/0.96 = $729.17
- [Total thm consumed - (Standby thm) - 100 thm] @ $0.05420/thm/0.96
- Balancing Charge (MPDQ) @ $0.02964/thm
- The MPDQ (Maximum Peak Day Quantity) is determined on an annual basis and is some what the analog of the 100 percent ratchet, of the electrical industry. The MPDQ is correlated to the maximum daily usage of gas plus the lowest average usage of gas per day during the months of June through September. The factor of (1/0.96) = 1.041666, is the Gross Revenue Tax on all transactions in NYS.

Standby Sales Service is the sum of the following:

- A daily nominated contract demand, typically 700 thm, @ $1.2098/thm = $846.86
- A gas commodity cost/month = 700 thm (in the above case) X Days/month X $0.387749/thm

- A gas "transportation" cost/month = 700 thm (in the above case) X Days/month X \$0.056606/thm.

Cash Out Therms:

- Net Imbalance (under delivery) represent the number of monthly standby therms plus those derived from other sources, such as the spot market. The costs are derived in terms of a fraction of [Total thm consumed, at the meter] X "Factor of Adjustment" (i.e., pipeline loss, currently = 1.0191).
- For that part of the underdelivery that represents 0 to 2 percent of the above number, therms are priced at \$0.524491/thm.
- For that part of the underdelivery that is between 2 to 10 percent of the above number, therms are priced at \$0.577023/thm.

NYS Import Tax: This number involves the: [Total thm consumed - Standby thm - Under delivery thm] X [0.159/1.02990] X \$0.04356/thm, the NYS tax. The factor of 0.159/1.0299 represents the (1997) NYS basis of wellhead price of gas, divided by 10 (for deca-therms), divided by the monthly BTU factor.

3.9.2.1 General Commodity under SC-8

The commodity cost is composed of two components: Standby Sales, and Transportation (to be distinguished from the preceding); both are subject to a 4.1666 percent Gross Receipts Tax.

3.9.2.2 Standby Sales

- Standby D1 Contract Demand Charge, for typically 20-30 Thousand Therms, @ \$1.15838/thm
- Standby Commodity Charge, that is of order \$0.219-\$0.289/thm
- Standby Transportation Charge @ \$0.05420/thm.

3.9.2.3 Transportation

- First 100 thm = \$700.0
- Remaining thm @ **5.1540¢/thm**
- Balancing Charge @ **2.8380¢/thm.**

In summary, a typical transportation cost is of order 8.6¢/thm, while a typical commodity charge is of order 48¢/thm.

3.9.3 Summary Comment

During the warm summer months of 1999, no gas was purchased through an outside vendor, as a more competitive price was available through the SC-8 standby sales to follow.

- *Standby D1 Contract Demand Charge*: ~ 20-30 K Therms = $1.15838/thm.
- *Standby Commodity Charge*: that is of order $0.219-$0.289/thm.
- *Standby Transportation Charge*: @ $0.05420/thm.
- *Transportation, under SC-8:* Examination of 1999 summer billing statements indicates that transportation fees are at least $700.0/Month, and could be of order 3 percent of the total above Standby values. BTU factor = 1.03.

3.10 Fort Eustis, VA

3.10.1 Electrical

Fort Eustis is on Virginia Power's Schedule MS Alternate. The tariff structure between Virginia Power and Fort Eustis has been carefully crafted to reflect the best interests of both consumer and utility, consistent with the requirement of load leveling, daily monitoring, and real time usage of electricity.

As such, many of the terms designated below vary from month to month with respect to magnitude, and are quantified not in terms of simple meter readings, but involve ratchets and running averages. These averaging techniques impact the Base KW Charge, Differential KW Charge/Credit, Contract KVA Charge and Base Energy Charges. The following rate structure is from Virginia Power's Tariff (Schedule MSALT), however the magnitude of the actual units found in the billing statements are explicit functions of the power consumption history, sampling time and of duration unique to a given parameter.

3.10.2 Demand Costs

- *Base KW Charge*: Basic KW Demand, computed as some fraction of the Measured Base KW X $10.0/KW
- *Differential KW Charge / Credit*: [Power Supply KW - Basic KW Demand] X $4.0/KW
- *Contract KVA Charge*: = $2.20/KVA for the first 5000 KVA, and $1.20/KVA for all additional KVA.

3.10.3 Energy Costs

- *Base Energy Costs*: All Base energy, in KWH, X $0.020971/KWH
- *Excess Energy Costs*:
  All ON-Peak KWH, X $0.035190/KWH
  All OFF-Peak KWH, X $0.029190/KWH
- *Fuel Charge Credit*: Total Base energy @ 0.6137¢/KWH.

Comment: Table 2 entries for Demand are the sum of Differential and Contract charges; Energy charges include ON Peak only.

3.10.4 Gas

From Schedule 6 (High Load Factor Firm Gas Delivery Service) billing data, these rates include the actual total cost paid to VNG for natural gas; the demand and contracted capacity volumes, were set during the preceding winter months of November through March, and units are $/100 CF.

- *Demand Rates*: $1.0433-$1.0397
- *Capacity Rates*: $0.01164-$0.01353
- *Delivery (transportation) Rates*: $0.0556
- *Commodity (for > than Contracted) Rates*: $0.2628-$0.2829
- *BTU Factor*: unknown (and assumed to be 1.025).

Comment: Table 3 entry for the Commodity (at > than Contracted) Rates includes transportation.

3.11 Fort Gordon, GA

3.11.1 Electrical

- *Cost*: 3¢/kWh for Energy ≤ 12.7 GWH/Mn
- *Cost*: [5.0 X (Energy/GWH) - 60]¢/kWh for Energy ≥ 12.75 GWH/Month
- *Schedule*: MLM-1
- *Energy Charges*: (June through September):
  - ON-Peak = 9.0¢/KWH
  - OFF-Peak = 1.4¢/KWH
  - Shoulder = 4.0¢/KWH
- *Customer Baseline Load*: 1.3548¢/KWH (yearly average, for all types of above power)
- *Incremental Energy*: 3.4¢/KWH (spot market).
- *Demand Charges*: Transmission Service (June through September)
  - ON Peak kW = $14.15/kW
  - Economy kW = $4.15/kW.

Excess Reactive Demand shall be the kVAR which is in excess of one-third of the measured actual KW in the current month for each metered service point. Each month excess kVAR will be billed at 27¢/ excess kVAR. There are additional fuel recovery costs, adjustments, and riders.

Comment: Choosing ON Peak values of Demand and Energy plus Baseline load gives the entries listed in Table 2.

3.11.2 Gas

- *(1) Interruptible Gas (EPA)*: $0.18801±10% / thm
- *Specified Firm Gas(EPA)*: $0.21601±10% / thm
- *(2) <u>Credit</u> for unused firm*: $0.05 / thm
- *Totals usage of (1) + (2)* = 405,000 thm
- AGL, Co. Transportation Charges, for all gas: ($0.0987 - $0.1165)/ thm.

Comment: Table 2 entry is the sum of Firm, Interruptible, and Transportation charges.

3.12 Fort Hood, TX

3.12.1 Electrical

- *Demand Costs*: (Total Demand (in KW) - 10 KW) X $7.63/KW.
- *Demand Greater than 56,000 KW/month*: rate is $8.63/KW.
- *Tiered Energy Costs*:
  - <u>First Tier</u> of 2500 KWH @ $0.0621/KWH = $155.25
  - <u>Second Tier</u> = (3500 + 215 X [Total Demand, in KW]). The resulting tier-2 cost is this number, in units of KWH, times $0.032/KWH.
  - <u>Third Tier</u> = Total Consumed Energy (in KWH) - the previously computed Tier-2 Energy (in KWH) - 2500 KWH. The resulting tier-3 costs is this number, in units of KWH, times $0.0059/KWH.
- *Fuel and Cogeneration Costs*: ($0.018402 + $0.000053)/KWH for all Total Consumed Power.

Comment: Demand value is chosen at the higher rate, and energy rate is the sum of Third Tier costs and fuel costs, yielding the entries listed in Table 2.

3.12.2 Gas

Fort Hood's gas is purchased through DESC and transported by Lone Star Gas Company. For the period of March 1999 to September 1999 Transportation costs are composed of taxes, backup transportation, interruptible charges, and were

fixed at 9.849¢/thm. During this period of time, the actual commodity cost spans between ($0.1877 to $0.29716)/thm. The final cost is the sum of these and averages about $0.358/thm over 1 complete year.

3.13 Fort Huachuca, AZ

3.13.1 Electrical

Electricity for Fort Huachuca is provided under Tucson Electric Power Company's LLP Rate Schedule 14. The demand charge is the average of the three highest peaks for the month, with a contract minimum of 4000 KW, and a minimum of 60 percent of the last 11 month's highest demand.

- *Demand Costs*: (Total Demand [in KW]) X $10.07/KW.
- *Energy Costs*: summer energy (in KWH) X $0.046466/KWH.
- *Reactive Power Factor Adjustments*: There is a power factor (Credit/Cost) of the Billing Demand X $0.013/KW times the percent above or below 90 percent, respectively.

3.13.2 Gas

- Tariff G-35: Gas service to Armed Forces
- *Margin Charge*: $0.18657 / thm
- *Gas Costs*: $0.25489 / thm
- *Rate Adjustments*: $0.06634 / thm

Gas is purchased on a DESC contract that varies monthly; actual reported data from DESC and the DPW at Fort Huachuca indicate the following rates, for period April through July of 1999:

- *Local Transportation Costs*: $0.07393 / thm
- *Gas Costs*: ($0.2075-$0.1615) / thm
- *Interstate Transportation Costs*: ($0.03895-$0.03660) / thm.

Comment: For premium power, adding Local and Interstate Transportation costs to that of Gas yields the Table 3 entry.

3.14 Fort Irwin, CA

3.14.1 Electrical

- *Demand*: $6.60/KW (Base Firm)
- *Energy*: Winter Base Firm:

  ON-Peak = 6.675¢/KWH

OFF-Peak = 3.478¢/KWH

- *Energy*: Other: (approximately 20 percent of total power)
  - ON-Peak: 4.841¢/KWH
  - SHOULDER: 3.874¢/KWH
  - OFF-Peak: 2.760¢/KWH
- *Energy*: Adjustments for all power: 0.396¢/KWH.

Comment: Demand entry for Table 2, as above. Energy entry computed as ~80 percent of Firm plus ~20 percent of ON Peak plus power adjustments.

3.14.2 Gas

In conversation, Mr. Rene Quinones indicated that propane gas is the only fossil fuel used at Fort Irwin, and the total price of commodity and transportation is: $0.493 / thm, averaged on a yearly basis.

3.15 Fort Jackson, SC

3.15.1 Electrical (Summer rates)

- *Energy Charges:*
  - *ON Peak*: 3.84¢/kWh
  - *OFF Peak*: 1.77¢/kWh
- *Demand charges*:
  - ON Peak: $13.72 $/kW
  - OFF Peak: $4.14 $/kW.

3.15.2 Gas

- *#6 Fuel Oil*: $0.3225 ± 12% / thm.

Rate Schedule 161 is for 300-1,500 MCF (gas equivalent) on a peak day; the present DPW claims that they use propane as little as possible (order of 10 days/year) when they get it from DESC, at DESC published rate of $0.345 ± 10% / thm, for last 14 months. (The ± 10% is derived from DESC data.) Schedule 951 for #6 Fuel Oil can provide a 15 percent reduction in cost relative to Sch 161, but requires usage of 1,500-3,000 MCF (gas equivalent) on a peak day.

3.16 Fort Knox, KY

3.16.1 Electrical

- *Demand Costs*: (Total summer, Demand [in KW]) X $8.54/KW.

- *Energy Costs*: Energy, in KWH, X $0.02444/KWH.
- *Reactive Power Factor Adjustments*: There is a power factor (Credit/Cost) of the above monthly demand charge that is decreased 0.4 percent for each whole 1 percent by which the monthly average power factor exceeds 80 percent lagging, and is increased 0.6 percent for each whole one percent by which the monthly average power factor exceeds 80 percent lagging, respectively. There exist fuel adjustment credits and other ancillary costs.

3.16.2 Gas

The differential supply is the difference between actual (BTU) deliveries to Fort Knox and first of the month nominations.

- *Firm Fixed price for 150,000 MMBTU*: $3.041 / MMBTU
- *Differential Supply Index Price*: $1.64 / MMBTU
- *Transport Fuel Factor, Supply and Transport Adjustments Factor (@ Differential)*: $0.5740 / MMBTU
- *Large Flow-Through, Fixed User Charges*:
  - Monthly Demand Charge (@ 9200 MCF) = $25,300
  - Monthly Commodity Charge = $0.1049 / MCF
  - Spot Market Charges = $1.8346 / MCF
- Btu factor is unknown (assumed = 1.025).

Comment: The differential supply is the difference between actual (BTU) deliveries to Fort Knox and first of the month nominations. Table 3 entry is the sum of Differential Supply Index Price, Transport Fuel Factor, Supply and Transport Adjustments Factor: ($1.60 + $0.560) / Dthm and Spot Market, Monthly Commodity Charges = $1.8922 / Dthm.

3.17 Fort Leavenworth, KS

3.17.1 Electrical

- *Billing Demand Charges*:
  - First 200 KW billed at: $4.33/KW.
  - Next 400 KW billed at: $4.14/KW.
  - Remaining KW of billing demand billed at: $3.95/KW.
- *Credit for Substation Ownership*: Billing Demand (KW) times $0.20/KW.
- *Energy Charges*:
  - First 50 X (Billing Demand) KWH at: 3.819¢/KWH.
  - Next 100 X (Billing Demand) KWH at: 3.312¢/KWH.
  - Next 250 X (Billing Demand) KWH at: 3.001¢/KWH.
  - Remaining KWH of energy usage billed at: 2.787¢/KW.

Comment: Choosing "remaining kWH" rate and substation credit, yields Table 2 entries.

3.17.2 Gas

- *Firm Fixed price for 500,000 thm*: $0.268 / thm
- *Differential Index Price*: $0.175 / thm
- *Differential Transpt. Fuel Factor*: $0.003535 / thm
- *Differential Supply Adjust. Factor*: $0.0025 / thm
- *Differential Transpt. Adjust. Factor*: $0.016 / thm.

Carry over from previous month's purchase are slightly higher than above index price. The typical final price is of order $0.26 / thm. Table 3 entry derives from the sum of the above differential terms.

3.18 Fort Lee, VA

3.18.1 Electrical

Fort Lee's electricity pricing is a proprietary amalgam of three rate structures: Virginia Power tariff number's 3, 4, and 10; the following is a brief synopsis of the relevant tariffs, for 30-day variable rate.

3.18.1.1 Schedule GS-3

- *(ON / OFF) Peak Demand Charge*: ($12.322/$0.665)/KW
- *All KW Distribution Demand Charge*: $1.50/KW
- *Reactive Demand Charge*: $0.15/rKVA
- *(ON / OFF) Peak Energy Charge*: (0.410/0.276)¢/KWH.

Each KWH is subject to a Fuel Charge.

3.18.1.2 Schedule GS-4

- *ON [At Primary Voltage] / OFF) Peak Demand Charge*: ($12.168/$0.641)/KW.
- *Distribution Demand Charge*:
  - First 5000 KW: $0.587/KW
  - Additional KW: $0.443/KW
  - Reactive Demand Charge: $0.15/rKVA
- *(ON / OFF) Peak Energy Charge*: (0.410/0.276)¢/KWH
- Each KWH is subject to a Fuel Charge.

3.18.1.3 Schedule 10

- *Contract Demand Charge*: $0.768/KW (All KW)
- *Distribution Demand Charge, Primary Voltage Customer*:
  - First 5000 KW: $0.587/KW
  - Additional KW: $0.443/KW
- *Distribution Demand Charge, Secondary Voltage Customer*:
  - All Demand KW: $1.500/KW
- *Energy Charges (May through September)*:

Day Classification	ON-Peak Rate/KWH	OFF-Peak Rate/KWH
A	26.036¢	2.899¢
B	2.221¢	1.445¢
C	1.445¢	0.988¢

Each KWH is subject to a Fuel Charge. Detailed comparison with the billing statements for the months of July and August of 1999, provided by the DPW of Fort Lee, indicate a rate structure that is virtually identical to that of Fort Eustis and is as follows:

Demand Costs:

- *Base KW Charge*: Basic KW Demand, computed as some fraction of the Measured Base KW X $10.0/KW
- *Differential KW Charge / Credit*: [Power Supply KW - Basic KW Demand] X $4.0/KW
- *Contract KVA Charge*: = $2.20/KVA for the first 5000 KVA, and $1.20/KVA for all additional KVA.

Energy Costs:

- *Base Energy Costs*: All Base energy, in KWH, X $0.020971/KWH
- *Excess Energy Costs*: All ON-Peak KWH, X $0.035190/KWH; all OFF-Peak KWH, X $0.029190/KWH
- *Fuel Charge Credit*: Total Base energy @ 0.624¢/KWH.

Comment: Table 2 entries for Demand are the sum of Differential and Contract charges; energy charges include ON Peak only.

3.18.2 Gas

Fort Lee's gas is transported by Columbia Gas of Virginia. The pricing is a proprietary amalgam of two rate structures options, Large General Gas: LGS and LGS-2. Each is composed of several different components: Firm, Standby, Inter-

ruptible, Curtailable service. The actual commodity is through DESC, which reviews the contract annually. Table 5 lists DESC data June 1998 to July 1999.

Table 5. DESC data June 1998 to July 1999 for Fort Lee, VA.

	Gas $/thm	Transport $/thm	Spread in Total $/thm
High	$0.239	$0.08672	$0.300
Low	$0.165	$0.02313	$0.1888

The DPW at Fort Eustis claims that Fort Lee's total gas rates should be comparable (but not equal) to those of Fort Eustis, so the above information does *not* include other significant transportation costs.

3.19 Fort Leonard Wood, MO

3.19.1 Electrical

Energy Costs: $0.025/KWH.

There is a monthly demand charge of $6.185/KW on the current (CY 2000) demand of 30,696 KW, which is expected to grow to a demand of 33,500 KW in CY2001. The demand is recalculated annually and is based on the highest 30 minute usage during a 12-month period, and is then leveraged over 36 months.

3.19.2 Gas (May, 2000 data)

- *Gas Price (NGI index Price)*: $3.1164 / MMBTU
- *Monthly Interstate Reservation Fee:* (on 5000 MMBTU) times a variable monthly factor; in May 2000. This was of order $10.62 / MMBTU.
- *Monthly Interstate Commodity Cost*: The number of consumed MMBTU (= actual metered amount) is multiplied by a variable monthly factor, in May 2000 this was of order $0.0395 / MMBTU. There is a Supplier Commodity rebate of $0.05 / MMBTU.
- *Fixed, by Contract, User Charges*:
  - Monthly Intrastate Reservation Fee fixed (on 7000 MMBTU) times a monthly factor of **$12.50 / MMBTU**. This unit price was negotiated at contract start up, and is stepped down annually.
  - Local Commodity Fee of **$0.21 / MMBTU**, this consumed unit price was negotiated at contract start up, and is stepped down annually.
  - Contractor Recapture Capitalization Charges: **$245,293** per month for the remainder of contract, and will be removed at time of next contract negotiation. Total final figure is typically **64¢/thm**.

Comment: For premium gas usage, the cost of gas includes Gas price, Interstate Commodity fees and surcharge, discount, and Local Transportation Commodity fees. Sequentially collecting these terms: ($3.1164+$0.0395-$0.05+$0.21) / Dthm = $3.316 / Dthm for the Table 3 entry.

3.20 Fort Lewis, WA

3.20.1 Electrical

- *Energy Charges*: 2.14¢/kWh
- *Demand Charges*: $4.43 /kW

3.20.2 Gas

For office building use, gas is purchased (effective April, 2000) on Schedule-85: "Interruptible Gas Service with Firm Option,"

- Firm Demand Charge — $1.99 / thm, for all daily therms
- Interruptible Gas Rates
  - First 25,000 thm — 40.141¢ / thm
  - Next 25,000 thm — 37.025¢ / thm
  - All over 50,000 thm — 34.550¢ / thm.

For Schedule-87 (> 10^6 thm / year), the interruptible gas rates are about 65–80 percent of the Schedule-85 rates.

3.21 Fort McClellan, AL

3.21.1 Electrical (Summer Rates)

- *Energy Charges:*
  - On-Peak: 6.05¢/kWh
  - OFF-Peak: 1.63¢/kWh
- *Transformation Charges*: $0.76/kW of Demand
- *Fuel Charges*: 1.357¢/kWh.

3.21.2 Gas

- Large Commercial F1, F2, I4
- *All Gas Wellhead Price*: $2.2280 / MMBTU
- *AGS Transport Charges (F1)*: $2.286 / MMBTU
- *AGS Transport Charges (F2)*: $2.220 / MMBTU
- *AGS Transport Charges (I4)*: $1.699 / MMBTU
- *Pipeline Charges (F1)*: $0.2784 / MMBTU

- *Pipeline Charges (F2)*: $0.2784 / MMBTU
- *Pipeline Charges (I4)*: $0.2495 / MMBTU
- *Volume Ratio of (F1 / F2)*: 0.502 for either AGS or pipeline.
- *BTU Factor*: unknown (and assumed to be 1.025).

Comment: Table 3 entries equal the sum of Wellhead price, both types of I4 charges, plus 33.3 percent of both types of F1 charges, and 66.6 percent of both types of F2 charges.

3.22 Fort McPherson, GA

3.22.1 Electrical

- For all Energy consumption less than 300 times the billing demand:
- First 50,000 KWH: 6.00¢/KWH
- Next 150,000 KWH: 5.82¢/KWH
- Next 800,000 KWH: 4.42¢/KWH
- Over 1,000,000 KWH: 4.10¢/KWH
- For all Energy consumption greater than 300 times the billing demand: 1.15¢/KWH
- *Excess Reactive Demand*: billed at $0.27/KVA.
- *Fuel Factor Costs*: Total Consumed Energy (in KWH) times: $0.013722/KWH, in addition to nominal Economy and Rate Case discount credits.

Comment: Assuming energy at greater than 300 times billing demand and fuel factor cost gives Table 2 entry.

3.22.2 Gas

Gas for Fort McPherson is purchased through Systems Engineering and Management Corporation (SEMC) of Knoxville, TN, which supplies billing statements for both commodity and transportation. Gas is contracted on the open market by SEMC, and listed commodity cost varies between: ($2.870-$1.620)/Dthm, during the months of March to September of 1999. The transportation cost for that period remains fixed at $0.7401/Dthm, as per information supplied by the SEMC vendor.

3.23 Fort Monroe, VA

3.23.1 Electrical

Fort Monroe is on Schedule MS Alternate, with a billing structure somewhat similar to that of Fort Eustis, above. However some differences do exist. The compiled billing data for the months of April to September of 1999 as supplied by the DPW at Fort Monroe, yield the following rates:

- *Base Energy Costs*: $0.01968/KWH
- *Demand Costs*: $10.52/KW
- *Reactive Demand Costs*: $0.15/KW
- *Fuel Credit*: (All KWH) $0.00294/KWH.

3.23.2 Gas

From billing data, these rates include the actual cost paid to VNG for natural gas; units are $/100 CF.

Table 6. Rates at Fort Monroe, VA, including the actual cost paid to VNG for natural gas; (units = $/100 CF).

Time of Year	Oct-Dec	Jan-Mar	Apr-Jun	Jul-Sep
1st 70 CCF	0.65738	0.68496	0.65315	0.69570
Next 430 CCF	0.63226	0.65986	0.62805	0.6706
Next 4500 CCF	0.60058	0.62816	0.59635	0.63890
Over 5000 CCF	0.56533	0.59291	0.5611	0.60365

The above rates are thought to include transportation, and are similar in structure to those of Fort Eustis. BTU Factor: unknown (and assumed to be 1.025).

Comment: Table 3 entry assumes most expensive rate between April and September at a consumption of greater than 5000 CCF.

3.24 Fort Polk, LA

3.24.1 Electrical

- *Demand Costs*:
  - First 60 KW = $277.20
  - All additional KW of Demand = $2.87/KW.
- *Reactive Demand in Excess of 50 Percent of Billed Demand* = $0.55/KVA
- *Tiered Energy Costs*:
  - <u>First Tier</u> = For first 30,000 KWH, 4.17¢/KWH.

- Second Tier: = 400 X [Billing Demand (in KW) - 75 KW]. The resulting Tier-2 cost is this number, in units of KWH, times 3.26¢/KWH.
- Third Tier = Total Consumed Energy (in KWH) - the previously computed Tier-2 Energy (in KWH) - 30,000 KWH. The resulting tier-3 costs is this number, in units of KWH, times 2.39¢/KWH.

There exist Fuel Adjustment Costs = Total Consumed Energy (in KWH) times a $0.02238/KWH, a Formula Rate Plan Reduction **credit** = Total Consumed Energy (in KWH) times 0.399¢/KWH, and a **credit** for primary voltage discount.

Comment: The Energy Costs equals the remaining KWH: 2.39 + ~ 28% of (2.238 - 0.399) = 2.905¢/KWH. The 28 percent (in the above "energy costs" explanation) is an estimate based upon one billing statement, and reflects the fractional portion of tier three to the whole. This is times fuel adjustments minus credits.

3.24.2 Gas

Gas for Fort Polk is purchased through Duke Energy, which supplies billing statements for both commodity and transportation. Gas is contracted through the DESC, and listed commodity cost varies between: ($0.185-$0.258)/thm, during the months of April to August of 1999.

Transportation for Duke Energy is supplied through KOCH Gateway Pipeline Company. DESC supplied billing statements reveal the monthly transportation costs for actual delivered gas varies between: ($0.169-$0.237)/thm, during the months of April to August of 1999.

There also exist fixed monthly pipeline FT-Demand costs (Firm Transportation), in the gas commodity pricing at $0.43075/thm for 42,000 thm and NN-Demand (No Notice Service) associated with a storage account, at $0.6840/thm for 8000 thm. When gas injection takes place, it is priced at the same monthly commodity costs as above.

Comment: For premium power rates, the most expensive commodity and transportation rate was chosen.

3.25 Fort Riley, KS

3.25.1 Electrical

- *Billing Demand Charges*:
  - First 200 KW billed at: $4.33/KW
  - Next 400 KW billed at: $4.14/KW
  - Remaining KW of billing demand billed at: $3.95/KW
- *Credit for Substation Ownership*: Billing Demand (KW) times $0.20/KW
- *Energy Charges*:
  - First 50 X (Billing Demand) KWH at: 3.819¢/KWH
  - Next 100 X (Billing Demand) KWH at: 3.312¢/KWH
  - Next 250 X (Billing Demand) KWH at: 3.001¢/KWH
  - Remaining KWH of energy usage billed at: 2.787¢/KW.

Comment: Choosing "remaining kWH" rate and substation credit, yields Table 2 entries.

3.25.2 Gas

Commercial Transport Charges, plus Kansas Transition Cost = $0.7073 / MCF, as per tariff. The DESC listed commodity cost varies between: ($0.1765-$0.2245)/thm, during the months of April to July of 1999. BTU Factor = unknown (and assumed to be 1.025).

3.26 Fort Rucker, AL

3.26.1 Electrical

For the main cantonment area, charges are for consumption only, under MTU. Starting 01/01/2000, the following rates pertain (from the Energy Coordinator):

- *Energy Charges:*
  ON Peak: 7.660¢/kWh
  OFF Peak: 3.180¢/kWh
- *Energy Recovery Charges:* 1.550¢/kWh.

3.26.2 Gas

- *The Commodity Rate*: The FT-NN Transportation Charge is $0.0229 / MMBTU, and includes five portions, some of which change annually.
- *The Firm Gas cost* is derived from an averaged rate: For any given month, the rates of the four preceding 30 day time periods, derived using the Southern FGT Zone 3 Index, are averaged together yielding a "base rate"; to this is

added a "JMP SWAP" component = $42,000/(Total Gas usage, in MMBTU, during the 120 days under consideration). A typical summer (99) value is $2.28787 / MMBTU.

- *Storage Costs*: $0.03011 / MMBTU
- *Gross Margin Costs*: $0.17307 / MMBTU. The resulting June 1999 value is of order $2.516 / MMBTU, or $2.5749 / MCF (using a BTU factor of 1.0234 MBTU = 1 CF).

The Demand Rate: The Demand volume was set on 4 January 1999, at 2,234 MCF, for the next 12 months. The Demand rate is presently $11.216 / MCF, of which a portion (about $0.55 / MCF) is derived from components that are variable on a quarterly and annual basis.

The DPW states that for July 1999, the commodity rate was listed at $2.46856/MCF and the demand at $11.249/MCF, both of which are in good agreement with the above. Using these values and the BTU factor gives the entries listed in Table 3.

3.27 Fort Sill, OK

3.27.1 Electrical

Cost: (2.3 ± 1.1)¢/kWh for all Energy usage.

Fort Sill has a type of "co-generation" capability.

3.27.2 Gas

Gas is negotiated through DESC on a yearly basis. The transportation is controlled by Tariff. The following is a distillation of present FY99 data.

- *Firm-Fixed Gas Price*: Typically $2.420 / MMBTU, with a recent low of $1.765 /MMBTU. The monthly volume for a given month is determined from an average derived from the previous 10 years.
- *The Differential (Index) Price*: controlled by the "spot market" and is of order $1.7653 (± $0.20) / MMBTU.
- *Gas Transportation*:
  - The "Demand" Charge is of the order ($1.2730 - $1.1030) / MCF, and there is a BTU adjustment charge of order (9.21 + 1.5)% times the Demand charge. BTU factor = 1.065
  - The "Upstream Pipe" Rate, Distribution, and LUFG (G3) charges total **$0.40246 / MCF.**

- For the months of February to May 1999, these total transportation charges ranged between ($1.247 to $1.421)/Dthm, as per DPW's records.

Comment: For premium power, the maximum differential index (~$1.96/Dthm) is added to the maximum transportation (~$1.42/Dthm) to give the entry listed in Table 3.

3.28 Fort Stewart, GA

3.28.1 Electrical

For the months of April to August of 1999, a typical cost for all Electrical Energy usage under Georgia Power Company's Schedule "MLM-1," is of order of (4.4 $\pm$ 0.8)¢/kWh.

- *Schedule*: MLM-1
- *Energy Charges*: (June through September):
  - ON-Peak = 9.0¢/KWH
  - OFF-Peak = 1.4¢/KWH
  - Shoulder = 4.0¢/KWH.
- *Customer Baseline Load*: 1.3548¢/KWH (yearly average, for all types of above power)
- *Incremental Energy*: 3.4¢/KWH (spot market).
- *Demand Charges*: Transmission Service (June through September)
  - ON Peak kW = $14.15/kW
  - Economy kW = $4.15/kW.

Excess Reactive Demand shall be the kVAR which is in excess of one-third of the measured actual KW in the current month for each metered service point. Each month excess kVAR will be billed at 27¢/ excess kVAR. There are additional fuel recovery costs, adjustments, and riders. Comment: Premium Energy considerations are as those of Fort Benning.

3.28.2 Gas

Fort Stewart's DPW claims that wood chips are the primary source of fuel for the Central Energy Plant, and are used for generating high temperature water and chilled water at the installation. The rate structures shown in Table 7 are derived from the actual billing statements, as supplied by DESC.

Table 7. Rate structures at Fort Stewart, GA.

Gas $/thm	Transport $/thm	Month of Usage
$0.27558	$0.06396	May 1999
$0.26095	$0.05658	June 1999
$0.2618	$0.05628	July 1999
$0.30171	$0.05616	August 1999
$0.32992	$0.04243	September 1999

Commodity plus Transportation average for the above months: 34 $\pm$ 3¢ / thm.

4 Results

The preceding chapter clearly shows that rate schedules for electricity and natural gas at individual installations are unique, dynamic, and can be quite complex. Also, the electric rate schedules are under rapid transition due to the on-going electric deregulation. The time required to collect the raw data from each installation typically spanned the months of February to December 1999; however more current entries have been made as data became available. The summer (cooling season) rates were emphasized. The raw data were either in the form of current electric and gas rate schedules, actual monthly billing statements, or information derived from the Defense Energy Support Center (DESC). Whenever possible, these raw data were cross checked with more descriptive information and actual billing statements and tariffs. Often, only one of these measures was available, usually the billing statements for natural gas and electricity.

4.1 Application of Results

The primary application of the results is the calculation of the economical benefit for gas cooling replacing the electrical cooling, which uses the electricity at the premium cost. An optimal use of electricity and natural gas for cooling application through the hybrid cooling systems is targeted for reduction of installation-wide energy cost for providing cooling service to its facilities. Due to the dynamic nature of these rate schedules, the following considerations should be given for analysis of each project.

1. The data was collected and analyzed over a period of 11 months, and as such represents a "snapshot" view of dynamic energy industry that is constantly in a state of flux. The accuracy of projected long-term benefit, based on the presented results, will be as good as the future changes at each installation.
2. Army installations are served by different utility companies, some of which are regulated, but many of which are not. The billing formats, tariffs, billing units (often, not stated) and pricing structures are unique to a given installation. Furthermore, they range from the simple to extremely complex, from the uncompromising proprietary to public domain. As such this significantly compounds and confounds the data collection process. A nontrivial consequence is the increased potential that some sort of non-systematic error could have been incorporated

into that data, either at the collection or analysis stage. A careful review of primary data for each installation of interest is recommended during an evaluation of a project.

3. With the caveats above, the presented results would be a valuable input for an engineer to evaluate the feasibility of gas cooling and/or hybrid cooling systems. Based on the data alone, the uncertainty level is expected to be of order 5 to 10 percent.
4. For further accuracy, the individual raw database should be reviewed. The minor parameters, such as use history, start up and phase out fees, higher order demand rates, time of use, storage charges, transportation fees, etc., may have a significant impact on the total rate structure for an installation of interest. Realizing this, every attempt was made to at least identify the existence of these parameters and quantify them whenever possible, so as to alert the reader to any subtlety that might further circumscribe the use of the data contained here. The listed Gas and Electric data for each installation attempts to systematically enumerate as many of these parameters as time and funding permitted, and is to be considered the primary archival data base for this report.

4.2 Further Recommendations

The cost of energy and the system first cost are the two most critical inputs in the life-cycle cost study of energy systems including the gas cooling and hybrid cooling systems. The energy industry is undergoing a rapid transition due to the on-going electric deregulation. As a consequence, the current electric rate structure is extremely dynamic in nature. Follow-up and update of energy cost data at a regular interval is strongly recommended for an accurate assessment of feasibility of energy systems in general.

5 Conclusion

This study has compiled a current (1999) snapshot of electric and natural gas rates at FORSCOM and TRADOC installations. The gathered information is intended to provide one of the two most important data required for a lifecycle cost analysis of natural gas cooling or electric/natural gas hybrid cooling systems. The data is presented for both gas and electricity (along with supporting comments), at two levels of reduction:

1. The marginal energy cost at each installation

2. The summarized raw data from each installation.

Note that the dynamic nature of electric rates, due to the on-going electric deregulation, warrants periodic update of the energy cost data in the future.

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42
8/00

REPORT DOCUMENTATION PAGE

Form Approved
OMB No. 0704-0188

1. REPORT DATE *(DD-MM-YYYY)*
August 2000

2. REPORT TYPE
Final

3. DATES COVERED *(From - To)*

4. TITLE AND SUBTITLE
Electrical and Natural Gas Rates for Cooling in Major Army Installations

5a. CONTRACT NUMBER

5b. GRANT NUMBER

5c. PROGRAM ELEMENT NUMBER

6. AUTHOR(S)
Chang W. Sohn and Carl A. Feickert

5d. PROJECT NUMBER
AT45

5e. TASK NUMBER
CF

5f. WORK UNIT NUMBER
X60

7. PERFORMING ORGANIZATION NAME(S) AND ADDRESS(ES)
U.S. Army Construction Engineering Research Laboratory (CERL)
P.O. Box 9005
Champaign, IL 61826-9005

8. PERFORMING ORGANIZATION REPORT NUMBER
ERDC/CERL TR-00-25

9. SPONSORING / MONITORING AGENCY NAME(S) AND ADDRESS(ES)
Headquarters, U.S. Army Corps of Engineers
20 Massachusetts Ave., NW.
Washington, DC 20314-1000

10. SPONSOR/MONITOR'S ACRONYM(S)
CEMP-ET

11. SPONSOR/MONITOR'S REPORT NUMBER(S)

12. DISTRIBUTION / AVAILABILITY STATEMENT
Approved for public release; distribution is unlimited.

13. SUPPLEMENTARY NOTES
Copies are available from the National Technical Information Service, 5285 Port Royal Road, Springfield, VA 22161.

14. ABSTRACT

The U.S. armed services and related supporting structures buy a significant amount of electrical power from the private sector during any given month. More than a third of the total electrical utility cost can typically be attributed to operation of air-conditioning and refrigeration equipment. Natural gas cooling systems offer savings in cooling cost by reducing on-peak electrical demand and, at certain sites, by reducing the cost of energy by using natural gas instead of electricity. This study compiled a current snapshot of electric and natural gas rates at FORSCOM and TRADOC installations for calendar year 1999. The gathered information is intended to provide data required for a lifecycle cost analysis of natural gas cooling or electric/natural gas hybrid cooling systems.

15. SUBJECT TERMS
cooling systems, electricity rates, natural gas rates, energy consumption, electric power, natural gas

16. SECURITY CLASSIFICATION OF:			17. LIMITATION OF ABSTRACT	18. NUMBER OF PAGES	19a. NAME OF RESPONSIBLE PERSON
					Chang W. Sohn
a. REPORT	**b. ABSTRACT**	**c. THIS PAGE**			**19b. TELEPHONE NUMBER** *(include area code)*
Unclassified	Unclassified	Unclassified	SAR	52	(217) 373-6739